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Project Summary

Demonstration of the Environmental and Demand-side Management Benefits of Grid-connected Photovoltaic Power Systems – 1994-1997

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The report gives results of an investigation into the pollutant emission reduction and demand-side management potential of 12 photovoltaic (PV) systems that began operation between June 1994 and July 1996 in various locations in the U.S. The project was sponsored by the U.S. EPA and 12 electric utilities. The report documents the project and presents analyses of each system's ability to offset emissions of sulfur dioxide, nitrogen oxides, and carbon dioxide, and to provide power during peak load hours for the host buildings and the participating utilities.

The analyses indicate a broad range in emission offsets resulting from PV system operation due to variation in the solar resource available to each system and variation in the marginal emission rates of the participating utilities. Each system's ability to provide power during peak load periods is investigated using gross and net (of PV generation) load duration curves. Differences between these curves provide insight into each PV system's ability to reduce the highest loads experienced by the host building or utility. One set of such curves is presented for each system and for each month of a 12-month performance monitoring period.

This Project Summary was developed by the National Risk Management Research Laboratory's Air Pollution Prevention and Control Division, Research Triangle Park, NC, to announce key findings of the research project that is fully documented in a separate report of the same title (see Project Report ordering information at back).

Introduction

In May 1993 the U.S. EPA issued the second of three solicitations for the installation of grid-tied PV systems with the goal of measuring their environmental and demand-side benefits. Following up on its success with the first solicitation, Ascension Technology's proposal was again selected from the proposals submitted.

Ascension's proposal was supported by 12 electric utilities, all of which ultimately participated in the project by installing a PV system. The participating utilities were 1) Boston Edison Company (BECO), serving the greater Boston area; 2)Public Service of Oklahoma (PSO), which has three service areas in eastern and central Oklahoma; 3) Consolidated Edison (CONED), serving New York City and Westchester County, New York; 4) Idaho Power Corporation (IPC), serving most of Idaho; 5) New York State Electric and Gas (NYSEG), with service areas concentrated in western New York state, 6) Nevada Power Company (NPC), serving Las Vegas and southern Nevada; 7) the Los Angeles Department of Water and Power (LADWP), which serves Los Angeles; 8) Public Service Company of Colorado (PSCO), serving Denver and other urban areas of Colorado; 9) the Arizona

Electric Power Co-Operative (AEPCO), which serves rural areas in southern Arizona; 10) Florida Power Corporation (FPC), serving the panhandle and gulf coast of Florida; 11) Atlantic Energy (ACE) (formerly Atlantic City Electric), which serves southern New Jersey; and 12) Duke Power (Duke), with a service area covering central and eastern North Carolina. In addition to the geographic diversity of the service areas represented by these utilities, their pollutant emission characteristics also proved to be quite divergent. Ascension Technology's partners from the PV industry were ASE Americas, which provided PV modules, and Omnion Power Engineering Corporation, which provided the inverters.

EPA awarded the contract for this project to Ascension Technology in September 1993. The final system design effort began shortly thereafter, and the first system was installed and operating in May 1994. Installations of the remaining 11 systems were completed over the course of the next 2 years.

Monitoring of each system began concurrently with initial system operation, although the "official data start date" was delayed at sites where there were initial technical problems with either instrumentation or PV system hardware. At each site, 15-minute average values of solar irradiance, ambient temperature, PV system power output, and building load were recorded and stored for subsequent retrieval by modem. Monitoring of each site for the purposes of this study continued for a period of 1 year.

Emission rate and load data provided by each participating utility were used in conjunction with the data collected from each system to conduct analyses of (1) the ability of each PV system to reduce the peak power demand of the building on which it was installed; (2) the chronological correlation of each PV system's power output to the respective utility's peak loads; and (3) the emission offsets resulting from operation of the PV systems.

Chapter 1 of this report provides a general introduction to the project. Chapter 2 describes the design, installation, and cost of each system. Chapter 3 describes the data acquisition system and presents data collection and review procedures. Chapter 4 describes the operating history and performance of each system in turn, and presents the results of the three analyses described above. Chapter 5 discusses the common operational problems encountered by this set of PV systems, and reviews the results of the emission offset and load matching analyses across all 12 systems. The authors' conclusions regarding the use of PV systems to offset pollutant emissions or for purposes of reducing peak building or utility loads are presented in Chapter 6.

PV Systems

All PV systems used in this project shared the same design but were installed in different parts of the country. Their performance, as measured by PV system outage, was affected by both systemic and environmental factors.

System Design

All PV systems installed under this project have a peak rating of 18 kW, and consist of three independent 6 kW subsystems, each with its own inverter. The inverter in each subsystem is fed by three parallel source circuits, each consisting of 10 PV modules in series. There are thus 90 modules in each system. All 12 installations utilize Ascension Technology RoofJack PV array supports, which have been used to install more than 1 MW of PV systems. PV arrays are held in place by ballast on flat roofs; this approach requires no roof penetrations for hold-down of the PV arrays. System design details were developed in close cooperation with Mobil Solar (now ASE Americas, Inc.), the PV module supplier. Omnion Power Engineering was selected as the supplier of power conditioners. The PV systems were designed to accommodate the specifications of the 6 kW-rated Omnion Series 2200 unit.

System Installation

Although the typical installation took only 3-4 days to complete, the final system did not begin operation until nearly 2 years after the first system's installation was complete. This prolonged period was due to numerous siting and code compliance difficulties encountered in the process of installing the systems.

With one exception, the systems were installed on the roofs of commercial and industrial buildings. The exception was the ground-mounted array on the campus of the University of Nevada at Las Vegas (EPA23). Table 1 summarizes the location of each system.

Table 1. Participating Utilities and Installation Locations

Site Name	Utility	Location
EPA 18	BECO	Boston, MA
EPA 19	PSO	Lawton, OK
EPA 20	CONED	Greenburgh, NY
EPA 21	IPC	Boise, ID
EPA 22	NYSEG	East Aurora, NY
EPA 23	NPC	Las Vegas, NV
EPA 24	LADWP	Los Angeles, CA
EPA 25	PSCO	Henderson, CO
EPA 26	AEPCO	Benson, AZ
EPA 27	FPC	Clearwater, FL
EPA 28	ACE	Pomona, NJ
EPA 29	Duke	Huntersville, NC

System Performance History

Of the 12 PV systems installed by this project, all but one suffered one or more events during the study period which temporarily limited system output or prevented generation altogether. Inverter-related problems were the most vexing of the generation-limiting events. In all, 22 inverter-related events resulted in a generation loss of 12,200 kWh, approximately 3.3% of the combined generation of these systems over the relevant time periods. Snow cover was also a frequent cause of PV system outages for those systems located in northern locations or at high altitudes. Accurate estimation of generation losses due to snow cover is not possible because the sensor used to measure sunlight (the primary input to simulation of the systems' performance) was usually covered by snow when the arrays were.

Only about 600 kWh of lost generation may be attributed specifically to module failures. Although such failures are known to have resulted in greater losses, it is not possible to separate these losses from those due to other equipment failures that occurred simultaneously. About 1,040 kWh (approximately 0.3% of gross generation) were lost due to faults in array wiring or problems with source-circuit protectors. Total generation by the PV systems was reduced by another 6,650 kWh (1.8% of gross generation) due to failures in utility equipment.

Results

The report describes results of this project in terms of pollutant emission offsets and load reductions for both the utility and the host building.

Pollutant Emission Offsets

Models of marginal emission rates (i.e., emission rates of load following units) were developed for each utility based on utility-provided data. The hourly emission

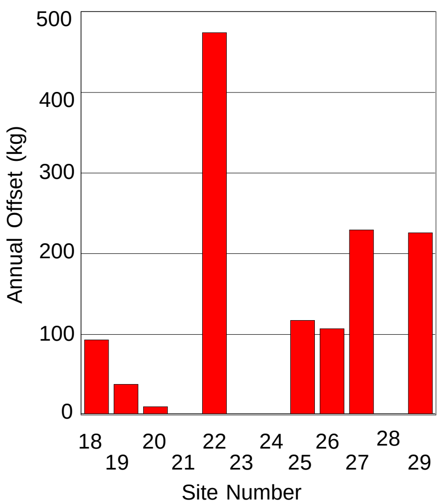

Figure 1. Annual Sulfur Dioxide Offsets.

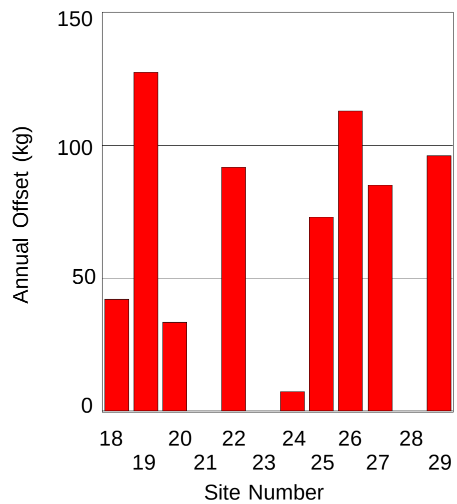

Figure 2. Annual Nitrogen Oxides Offsets.

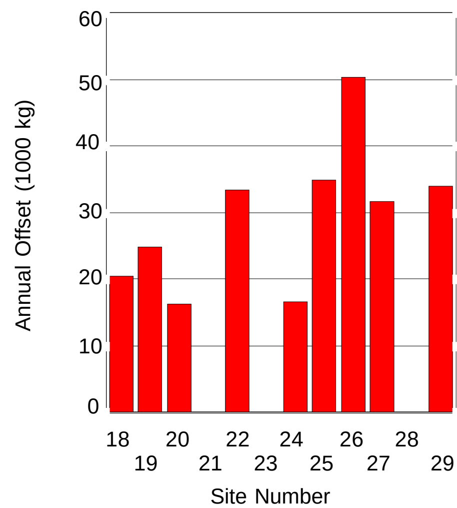

Figure 3. Annual Carbon Dioxide Offsets.

rates of sulfur dioxide (SO_2), nitrogen oxides (NO_x), and carbon dioxide (CO_2) were then combined with hourly PV system generation data to determine hourly emission offsets.

Annual emission offsets are presented in Figures 1 through 3. Note that insufficient data were provided to determine marginal emission rates for sites EPA23 and EPA28, and that generation by system EPA21 offset hydroelectric generation and therefore resulted in zero offsets of all three pollutants. Aside from these three systems, annual SO_2 offsets ranged from less than 80 g for a system offsetting generation by natural-gas-fired combustion turbines to 475 kg for a system that offset the generation of a coal-fired power plant. Annual NO_x offsets ranged from 8 to 128 kg, and the range in annual CO_2 emission offsets was from 16,700 to 50,400 kg.

The extreme variability in these results is due to four factors: 1) the pollutant emission rates of each utility's load-following generating units; 2) the installed capacity of the PV systems; 3) the local solar resource available to each system; and 4) the operating performance (i.e., reliability) of each system. Of these, utility emission rates were the most influential factor in determining offsets, particularly for SO_2. The installed capacities of the 12 systems installed under this project were identical, and therefore did not play a role in inter-site differences in emission offsets, but variations in the solar resource and reliability of the systems certainly did.

Since there are currently no mitigation measures in place for CO_2, variation in utility CO_2 emission rates is due only to the relatively small (about 2:1) variation in the carbon content of fuels used and variation in the heat rates of the power plants. The range of the highest to lowest annual offset is relatively small at 3.0. For the other pollutants, variations in the pollutant content of the fuel as well as inter-utility differences in type and efficiency of the load-following generators and installed pollution mitigation equipment give rise to the tremendous differences between utility emission rates which underlie the differences in emission offsets described above.

Host Building Load Reduction

Each PV system's ability to provide power during building peak load hours was analyzed by comparing each building's monthly net (of PV generation) and gross load duration curves (LDC). The LDC is constructed by sorting all load values for a given period in descending order, and plotting each value against its rank in the sort. Differences in a building's net and gross LDC for the highest load values indicate the PV system's ability to provide power during peak load periods. Figure 4 presents an example of gross and net LDCs for one of the host buildings.

Some of the host buildings in this project had loads very well suited to peak-shaving by the PV system, while others always experienced their peak loads at times of low irradiance. During the 25 highest load hours in the months in which each host building experienced its highest load (during the monitoring period), the average reduction in the building LDC ranged from 5 to 72% of system rating.

Analysis of the data collected through this project revealed that the total annual

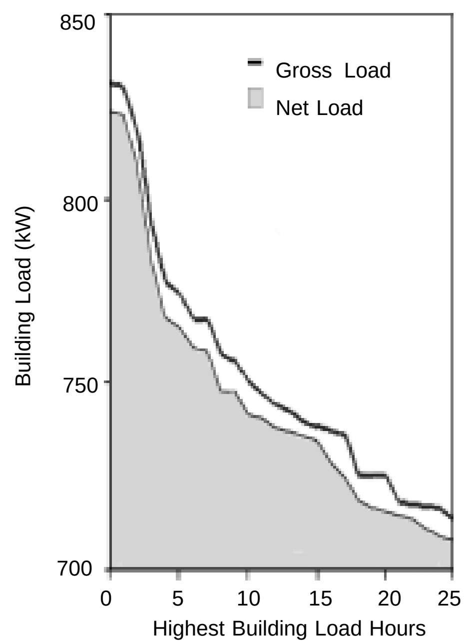

Figure 4. Gross and Net LDCs.

insolation available at a given location indicates little about the ability of a PV system to provide power during peak load hours. Several of the systems that provided the most power during peak load hours also had among the lowest annual insolation. Conversely, some of the sites with the greatest solar resources proved to be among the worst load matchers in the group.

Another conclusion resulting from this analysis is that a PV system's operation during one or a small number of peak building load hours may provide an inaccurate picture of that system's capacity value. If a building's highest load(s) occur during mid-day hours but the building also has near-peak loads occurring at times of low or no irradiance, the near-peak loa!ds will remain unaffected by the PV system, and will migrate upward in the building's net LDC. If the difference between the daytime peak load(s) and the nighttime near-peak load(s) is small relative the PV system's capacity, the difference between the building's gross and net LDCs may be substantially smaller than the PV system's power generation during the daytime peaks.

Conversely, if a PV system generates at a low capacity factor during the highest building load hours, but provides more power at times when building load is near its peak level, it may be important to consider whether the conditions that resulted in the building's highest loads are representative of typical conditions for the building.

Use of gross and net LDCs allows one to review the effect of PV system operation on as many or as few of the highest load hours as is desired, and is an essential tool in assessing the capacity value of a PV system.

Utility Peak Load Reduction

Conclusions regarding peak load reduction at the utility system level are much the same as those discussed above for building peak load reduction. For some of the utilities participating in this study, PV systems can be very effective at providing power during periods of peak load, while for other utilities whose peaks occur at times of low or no irradiance, the technology provides little capacity value. In the months in which each utility's peak load occurred, the reductions of the utilities' LDCs over the 25 highest load hours ranged from zero to 71% of PV system rating.

As discussed above for building load, the annual insolation available to a PV system has little to do with its ability to provide power when it is most needed. The three systems that had the highest levels of annual insolation yielded among the lowest LDC reductions during the utility's peak load month, and the system that provided the most support to its utility in the peak load month was ranked 10th in annual insolation.

Finally, the use of chronological data alone to interpret the capacity value of PV may be deceiving. If near-peak utility loads occur at times of low irradiance, even a very large PV system (or set of systems) would do little to reduce the peak of the utility's LDC, even if that system operates at a high fraction of its rating during the highest load hour or several hours. Again, in assessing the capacity value of PV systems, it is essential to determine how the resource would alter the utility LDC.

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Ronald J. Spiegel is the EPA Project Officer (see below).
The complete report, entitled "Demonstration of the Environmental and Demand-side Management Benefits of Grid-connected Photovoltaic Power Systems – 1994-1997," (Order No. PB98-145311; Cost: $44.00, subject to change) will be available only from

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